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SELECTION OF INSTALLED CAPACITY AT HYDROELECTRIC POWER PLANTS

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POWER DIVISION

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SELECTION OF INSTALLED CAPACITY AT HYDROELECTRIC POWER PLANTS

Lesher S. Wing,[1] and Robert H. Griffin,[2] A.M. ASCE

SYNOPSIS

This paper presents a synthesis of procedures generally used to determine installed capacity at hydroelectric plants. After stating necessary definitions, this paper outlines certain fundamental concepts. Four criteria for determining benefit-cost ratios are discussed, and their significance stated. The hydro installation determined by combining a single hydro plant with steam support in the most economic manner to serve a homologous segment of the system load is illustrated, and the limitations of this method are discussed. The critical incremental load factor is defined, and is recommended for use in determining ultimate hydro-installed capacity. A proposed method of determining hydro installations, by selecting the lowest-cost increments of hydro capacity and energy, is illustrated and recommended. Various phases of power-system development are described, and the hydro plants that should be designed for future expansion are identified. Special problems of installation at storage plants are discussed, and considerations leading to selection of optimum drawdown and critical head are set forth.

INTRODUCTION

Selection of the proper installed capacity at a potential hydroelectric power plant is a common problem in many engineering offices dealing with electric power supply. The basic consideration is very simple. It is to supply the system load at the lowest system cost. However, because the power supply problem differs widely among systems, and varies from year to year in each system, there has been a marked lack of unanimity of procedures and conclusions. It is the opinion of the writers that the basic ideas are essentially simple; and that the problem becomes complex because the required studies are not separated into logical units, and because the problem frequently requires consideration of load growth and of many plants, both existing and potential.

In this paper it is assumed that the hydrologic, hydraulic, load, and transmission studies have been completed, at least in a preliminary form. Basic

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data as to topography and other factors have been obtained, duration curves of power output have been prepared, and cost estimates, including transmission, of at least preliminary accuracy are available. The authors realize that preliminary estimates of cost and output are frequently in error. If sufficient time and money are available, the estimates can be refined to any degree desired. In the more usual case, however, the engineer is compelled to use his judgment, based on preliminary surveys and estimates, in selecting the most favorable projects for detailed investigation. It is the purpose of this paper to set forth certain concepts, methods, and procedures, which will be useful to those concerned with problems of hydroelectric-power plant economics. An orderly procedure is outlined for determining the maximum feasible installed capacity at any given plant, and the most economic installation for each phase of system power supply.

The part of this paper following the introduction and the statement of fundamental concepts is concerned primarily with the economics of hydro-plant installations at various stages of hydro-steam system development. Special problems related to variable-head storage plants, where the reservoir drawdown may be great enough to reduce the peaking capability of the plant, are then considered. In many cases these storage plants are multipurpose projects involving power, flood control, navigation, irrigation, and other functions. The allocation of reservoir space among the various uses, and the even more difficult and controversial questions of cost allocation, do not form a part of this paper. Although the proposed procedures are intended for use after the allocation and operation problems have been solved, certain of the concepts may be helpful in the economic considerations leading to a reasonable allocation of physical facilities and cost.

Fundamental Concepts

Definitions

The following definitions of terms used herein conform, in general, to those adopted for use by the Federal agencies.[3]

Prime Power. Hydroelectric power available from a plant on a continuous basis under the most adverse hydraulic conditions contemplated.

Firm Power. Power intended to have assured availability to the customer to meet his load requirements.

Firm Energy. Electric energy associated with firm power.

Secondary Energy. All hydroelectric energy other than that available from continuous power.

Prime Energy. Hydroelectric energy which is available from continuous power.

Cost of Prime Power. The cost of obtaining the continuous power from a hydroelectric plant. This is the dam and reservoir cost allocated to power, plus power-plant facilities needed to generate prime energy.

Peaking Capacity. Capacity in excess of the continuous or prime power.

3. "Glossary of Important Power and Rate Terms, Abbreviations, and Units of Measurement," prepared by the Federal Inter-Agency River Basin Committee.

Cost of Peaking Capacity. The cost of capacity of a hydroelectric plant installed in excess of that needed to obtain the prime energy.

Gross Cost of Incremental Hydro Capacity. The total annual cost of an increment of capacity at a hydro-electric plant.

Net Cost of Incremental Hydro Capacity. The annual total cost of an increment of hydroelectric capacity, less the value of the marketable, or usable, portion of the secondary energy made available by the increment.

Annual Storage. Storage, in addition to pondage, that can be filled every year, and used to increase system-prime energy.

Cyclic Storage. Storage, in addition to annual storage, that can be used to increase system-prime energy.

Hydro-Steam Ratio. Hydro and steam dependable capacities, each expressed as a percentage of the system total; i.e., 80-20, 70-30, etc.

Critical Head. The head on the turbine at which turbine capacity at full-gate opening permits the generator to operate at rated capacity.

Benefit-Cost Ratio. The ratio of the sum of the capacity and energy benefits to the total annual costs relating to the hydro project; also, used in connection with hydro capacity and energy, separately.

Value of Power

The value of power is assumed to be the cost of steam-electric generation at load center. Equivalence of capacity and energy produced and evaluated is necessary in all cases. It is the writers' opinion that cost of steam power is the most reasonable basis for power-system economic studies of hydroelectric-plant installed capacity. Even if other concepts of value of power are developed and used, the value should be expressed in terms of its two components—capacity and energy.

Costs of Hydroelectric and Steam Power Plants

The power-plant costs used in this paper are "at market," and are intended to be typical of projects under study by Federal agencies. Different hydroplant and steam-plant costs would, of course, change the economic comparisons and affect the installed capacity, but do not invalidate the methods suggested. The fixed and operating costs used should be those applicable to the construction agency.

Reserve Capacity

Throughout this paper the writers have purposely omitted consideration of reserve capacity. Reserve capacity should, of course, be provided in the system. Its location and amount are influenced by many factors, and constitute a separate problem.

It is also assumed, in some cases, that steam plants may operate through the adverse hydro period at 100 percent capacity factor. This has been done solely to simplify the presentation. Other assumptions could be made. However, no change in basic method or procedure would be needed.

Transmission Cost

Nearly all hydro plants require transmission facilities to deliver their

capacity and energy to market. All comparisons in this paper are based on "at-market" values and, where costs are given, the cost of the necessary transmission is included. Appropriate allowances for transmission losses are assumed to have been made in estimating hydro-electric output. Determination of the transmission required, its cost, and the allocation of transmission costs among the various sources of power supply are separate problems, which are not discussed herein.

Criteria for Economic Justification

Various criteria for economic installation at hydro plants have been proposed. The more usual are: (1) Installation which yields maximum rate of return on the investment (highest benefit-cost ratio of plant); (2) installation which yields a benefit-cost ratio of unity for the incremental hydro-plant capacity; (3) installation which yields a benefit-cost ratio of unity for the plant; (4) installation at plant, which in combination with other plants yields the lowest system cost. The first three criteria mentioned above are illustrated in Figure 1.[4] These all refer to an isolated plant.

The criterion of maximum rate of return on the investment may indicate too large an installation initially. If used to determine the ultimate installation, it is apt to result in a shortsighted policy of "skimming the cream," leading to increased future costs, the pre-emption of large, economic, hydroelectric sites by small plants, and waste of resources. Most governmental and large private organizations now follow comprehensive basin-planning policies, and eschew this approach.

Installation up to the capacity at which the benefit-cost ratio of the last small increment is unity, is a useful concept. As will be shown, it is a simple and convenient criterion for determining the maximum economically feasible hydroelectric-plant installation.

Installation of capacity for a plant benefit-cost ratio of unity means that increments of capacity are added beyond the increment having a benefit-cost ratio of unity. In the writers' opinion, this is not a realistic criterion for determining the ultimate capacity of a plant. It should be used only if some overriding necessity compels the development of power regardless of cost.

The fourth criterion, installation for lowest system cost, is applicable at all stages of system development. As indicated in the introduction, the writers regard it as the basic criterion in determining the capacity to be installed at any time. When properly applied with regard to load growth, it results in the best possible system, and one with the most favorable benefit-cost ratio for the system load then existing. It is the basis of the selection of economic installed capacity used in this paper.

Comparison of Hydro and Steam Costs

Analyses of costs and value are simplified if hydro and the corresponding steam costs are divided into two components:

1. Cost of prime power.
2. Cost of incremental peaking capacity.

The cost of hydroelectric-prime power is determined by the fixed and

4. From the May 1950 "Report to the Federal Inter-Agency River Basin Committee, Proposed Practices for Economic Analysis of River Basin Projects," prepared by the Subcommittee on Benefits and Costs.

operating costs of the facilities needed to deliver maximum continuous plant output to load center during the most adverse water-supply period contemplated. Effects of storage regulation, irrigation diversions, flood control, navigation, and any other factors affecting water supply are included in determining the output. The annual cost of prime power, therefore, includes all, or the allocated part, of the annual costs of dam, reservoir, rights of way, easements, rail and highway relocation costs, damages, transmission, etc., as well as the cost of power facilities required to generate the prime power.

The gross cost of each additional increment of hydro-peaking capacity is the cost of power facilities required for the increment. Intakes, penstocks, surge tanks, turbines, electrical equipment, and transmission must all be larger, or be charged with higher losses as each increment is added.

The net cost of peaking capacity is the gross cost defined above less the value of the secondary energy, which the increment of capacity makes available, and which is salable or usable as steam replacement under the load curve. If the water supply is completely regulated, no secondary energy would be made available. However, in most cases the first increment of peaking capacity above prime allows production of a relatively large amount of secondary energy. Succeeding increments of capacity produce less and less energy, until a point is reached when all the water of the stream is utilized and no secondary energy is produced by additional capacity.

The cost of prime energy at a steam plant is the cost of operating the plant at 100 percent load factor.[5] The cost of steam-peaking capacity is comprised of the fixed charges and fixed operating expenses of an increment of capacity ready to generate energy. This cost corresponds to the net cost of hydro-peaking capacity. The gross cost of hydro-peaking capacity corresponds to the fixed steam costs plus the cost of steam energy equivalent to energy produced by the hydro increment.

Three Phases of Hydro Operation

In areas rich in hydro resources throughout the western States, hydropower supply frequently passes through three phases of development. Since the planning of hydro-plant installations and related facilities should recognize the changing pattern of hydro operation and its effect upon the long-term economics of the hydro development, these three phases will be briefly described.

Phase I

In areas where there is a relatively large amount of hydro power available at costs less than steam power, the load may be served at first entirely by hydro. Usually, a high degree of streamflow regulation is uneconomic or unnecessary at the start, and load requirements are "carved out" of the potential hydro-prime generation. This results in a considerable amount of potential secondary energy. This stage of development is defined herein as Phase I.

In order to obtain more prime hydro to serve the growing load, additional

5. Maximum practical operation over an extended period of time would be about 85 percent plant factor; however, a 100 percent plant factor has been used to simplify the presentation.

streamflow plants, storage-reservoir plants, or both, are added to the system. In many cases, cyclical storage is developed in addition to that used annually. Reservoir rule curves are developed to protect prime energy in the critical period, even at the sacrifice of dependable-peaking capacity. The end of Phase I is reached when steam in combination with hydro becomes economic to serve the load.

Phase II

In the second phase, the system is expanded by developing the more difficult and costly hydro sites to meet growth of load. In this phase, steam and hydro can be economically combined, and the load served at less cost by the combination than by either hydro or fuel plants alone. Hydro secondary is firmed either by added steam plants, by hydro storage, or by both, to give the lowest cost. The cost of additional hydro-peaking capacity at site, plus transmission to load centers, will frequently be less than alternative steam costs. Under such conditions the hydro capacity would be developed. The end of Phase II is reached when all economically feasible hydro plants have been built, and the then existing hydro-steam system is being operated at its maximum benefit-cost ratio (lowest unit cost).

Phase III

In the third phase, high load-factor steam generation is required to meet load growth. To the extent that it is economic, additional peaking capacity is added at existing hydro plants. With further growth of system load, the hydro-steam ratio rapidly changes and steam-installed capacity overtakes and exceeds that of hydro. In this stage, the economics of cyclical storage at sites having plant installations in excess of dependable capacity will change; and finally it will become uneconomic to draw storage below the critical head at most storage projects, if it will impair the dependable-peaking capacity.

* * * * *

In Phase III all plant additions for energy, and in most cases for peaking also, are at steam plants. Actually, the dividing line between Phases II and III is seldom sharp, because of the changing relationship of hydro and steam costs. A system in the early part of Phase III will likely have available some hydro plants with incremental capacity costs less than steam. These plants will be further expanded, and operated at lower load factors. Also, additional hydro projects may become economic because of rising fuel cost, a reduction in construction costs, or other reasons; and such projects would be developed. At any given date, or phase of system development, the proper hydro installation depends on many factors besides those directly relating to the plant. One of the most important is the size of the system in relation to the available hydroelectric supply at costs equal to or less than steam.

Most Economic Hydro Plant Installation With Steam Support

Hydro-plant installations have frequently been estimated by determining the hydro installation, which with firming steam results in the maximum benefit-cost ratio for the combination, when operated as an isolated system. Because of its common use, this method will be illustrated. In a later section, it will be compared with the method recommended by the writers, and

its limitations discussed. Since it includes steam-electric generation, it is not applicable to Phase I conditions.

Plant A, having the duration curve of Figure 2,[6] is operated in conjunction with a single steam plant to serve a load having certain fixed characteristics. The size of the load is the maximum that can be served by the assumed hydro-steam combination. The method consists in assuming a convenient series of hydro installations; determining the corresponding energy from the duration curve; assuming a series of hydro-steam ratios; and computing resulting system annual costs and benefits. The dependable capacity of the hydro installation and the hydro-steam ratio determine the system size. The hydro-steam ratio must be such that all of the hydro capacity and energy available with that capacity are usable under the load curve.

An integrated system-load curve, plotted on the basis of one kilowatt of system load, is convenient for use in such a study. A typical load curve for a 65 percent annual load-factor load is plotted in Figure 3. Since it is on a unit basis, it applies to any size system having the same load characteristics. This curve,[7] together with the hydro-plant duration curve (Figure 2) and the applicable hydro and steam costs, can be used to determine the best hydro-steam ratio. The costs used for Plant A, shown in Table 1, are: For prime hydro, $37.34; for gross incremental hydro capacity, $13.02; for steam capacity, $16.84; and for steam energy, 3.18 mills per kilowatt-hour.

In Table 1, column 1 is a series of practical installations; column 1(a) is the annual hydro cost per kilowatt of the installation; column 2 is the energy in continuous kilowatts per installed kilowatt in the adverse year; and column 3 is the energy in average kilowatts per installed (also dependable) kilowatt available in the average year, derived from the duration curve (Figure 2). The maximum hydro-steam ratios, columns 4 and 4(a), are determined from the integrated system-load duration curve, Figure 3. In this figure the plant-factor slope lines are plotted "from base," and their intersection with the load curve corresponds to the maximum hydro-steam ratio; that is, to the ratio that will permit complete utilization of the available hydro energy and peaking capacity. For example, for 91.3 percent plant-factor hydro, the maximum hydro-steam ratio (with hydro in base) is about 60-40. For 100 percent plant factor, the ratio would be 45-55. Sixty-five percent load-factor energy is the lowest that will operate in the load from base. For this condition, the hydro-steam ratio is 100-0. Firm energy at load factors below 65 percent must operate from peak.

To determine the hydro-steam ratio when the hydro energy is used in the peak, lines parallel to those shown should be drawn through the extreme peak. Their intersection with the load curve defines the hydro-steam ratio under this assumption. For instance, the 50 percent plant-factor slope plotted from peak intersects the load curve at about .7 kilowatt from peak, which corresponds to a 70-30 hydro-steam ratio.

It is necessary to examine both the critical-year and average-year plant factors, and to determine the maximum hydro-steam ratio for each, since either may impose limitations. The critical-year energy can support only a definite amount of firm capacity on the load. Likewise, if no average-year

6. Potential outputs also given in columns 3 and 4, Table 5; and in column 2 of Table 3.
7. The curve in Fig. 3 is based on annual load characteristics; it is usually desirable to use seasonal, and in some cases monthly, curves in making the analyses described in this paper. The annual curve is used for illustration only.

energy is to be wasted, there must be opportunity to absorb it. The lower of the two hydro-steam maximum ratios so determined should be used, unless it is decided to waste some secondary energy, if the latter should be the limiting factor.

In column 5, Table 1, several assumed hydro-steam ratios ranging up to the maximum are given for each size of hydro installation. The maximum ratio is equal to the lower of the two limiting hydro-steam ratios shown in columns 4 and 4(a). Columns 6 and 7 are computed from the energy in columns 2 and 3 and the hydro-steam ratio. Column 8 is determined by subtracting the average available hydro energy per kilowatt of system peak (column 7) from the system total requirement of 5700 kilowatt-hours per kilowatt (.65 x 8760 = 5700). Columns 9, 10, and 11 are costs per kilowatt of system peak. Column 9 costs are computed from the amounts given in column 8. The costs in columns 10 and 11 are based on the corresponding hydro-steam ratios shown in column 5. Column 12 is the sum of columns 9, 10, and 11, and is the total system annual cost in dollars per kilowatt of system peak.

It is apparent from column 12, that for each hydro installation the minimum system cost is attained when the hydro-steam ratio is the maximum feasible; this corresponds to the minimum system size that utilizes all hydro-firm and secondary energy. This could have been predicted, since the system is made up of a low-cost element (hydro) and a high-cost element (steam). Obviously, the less steam used the lower the system cost.

For the first two increments of capacity at Plant A, the effects of the cheap hydro capacity and energy outweigh the additional high-cost steam energy required; and the minimum system cost for each of these two installations is lowered. For the third and succeeding increments, the high cost of increased steam power predominates, and the minimum system cost increases. Column 12 indicates that the best hydro-steam ratio is 70-30, occurring with a hydro installation of about 50,000 kilowatts.

Since in all cases in which hydro is economically feasible the minimum system cost occurs with the maximum hydro-steam ratio, only that case need be investigated. Columns 13 and 14 apply to Plant B, an assumed hydro plant with the same duration curve as Plant A, but with a prime-power cost of $30.00 (instead of $37.34). Gross cost of peaking capacity is $13.02, as for Plant A. The minimum system cost ($24.69) occurs with a hydro installation of 35,000 kilowatts. Since one of the elements of hydro cost is lower (and the other the same), the minimum system cost is lower for Plant B than for Plant A. Also, since steam costs are relatively higher for Plant B than for A, their effect predominates at a lower installation; that is, 35,000 instead of 50,000 kilowatts.

Plant C, with a prime cost of $45.00 and a gross peaking-capacity cost of $13.02, has a minimum cost of $30.13, also at 50,000 kilowatts of hydro installation. Plotting the data in the table, or computing smaller increments, would demonstrate that the best installation for Plant A is about 43,000 kilowatts; for Plants B and D slightly less; and for Plant C slightly higher.[8]

8. A subsequent more detailed analysis of installations in the 35,000 kw-50,000 kw range, indicates that the most economic size of installation occurs between 40,000 kw and 45,000 kw in each case. The adoption of these installations would change some of the amounts given in the tables and discussion, but would not affect any of the proposed procedures or conclusions.

Plant D is assumed to have a prime-power cost of $30.00, and a gross cost of incremental peaking capacity of $19.10. The minimum cost (Table 1) of $25.73 per kilowatt-year occurs with an installation of 35,000 kilowatts. As in the other cases, the system is assumed to consist of a single steam and single hydro plant, serving a load of specified characteristics and of a magnitude determined by the energy of the hydro plant and the hydro-steam ratio.

When the load has grown to the point where each hydro plant has been expanded and combined with its most economic steam component, the combination of the four "systems" of Table 1 has a total capacity—or serves a load—of 259,522 kilowatts.

Our system now has a hydro installation of 170 megawatts, and a steam installation of 89.522 megawatts. The capacity is distributed as follows:

Plant	Kilowatts	
A	50,000	(The loadings of
B	35,000	the plants are
C	50,000	shown below the
D	35,000	load curve on Fig. 4)
Total Hydro	170,000	
Steam	89,522	
Total System	259,522	

As will be shown, this is not the most economic combination of installations for this load. It is, however, a reasonable combination for the Phase II system load of the size indicated. The "system" costs are summarized in Table 2. They total $7,052,550 annually.

Proposed Procedures for Determining Installed Hydro Capacity

Economic Combinations of Hydro-Prime Energy and Peaking Capacity

There are three fundamental relationships between hydro-prime costs and steam costs; and, similarly, three for incremental hydro. This results in nine possible combinations of prime and incremental costs; however, only seven are significant. The six fundamental relationships are as follows:

Prime Power

(1) Prime Hydro Cost = Steam Cost
(2) Prime Hydro Cost < Steam Cost
(3) Prime Hydro Cost > Steam Cost

Incremental Capacity Above Prime

(A) Net cost of incremental hydro capacity = Steam Cost
(B) Net cost of incremental hydro capacity < Steam Cost
(C) Net cost of incremental hydro capacity > Steam Cost

If condition (1) exists in combination with (A) the plant is barely feasible, and in most cases the project would be delayed and a search made for more

favorable sites. This combination has no advantage over steam. If condition (1) (B) exists, the installation is definitely feasible, and it may be expanded up to the physical or economic limitations established by the site, the size and characteristics of the system load, and the cost of power from other sources—existing or potential. If combination (1) (C) exists, incremental peaking capacity is not feasible, prime capacity is barely feasible, and the plant should not be developed until all sites costing less than steam have been utilized. Even then, the installation must be limited to that required for prime power.

If prime power costs less per kilowatt than steam, condition (2), additional capacity can be economically installed under combination (2) (B). Under combination (2) (A), peaking capacity is obtained at a cost equal to steam, but there is no economic gain. In this case, the installation would probably be governed by some condition other than the relative hydro-steam cost. If peaking capacity costs more than steam, combination (2) (C), the installation should be limited to that needed to obtain prime power.

If prime power costs more than steam, condition (3), it can be developed only if peaking capacity at the site can be developed at a net cost less than steam capacity, combination (3) (B). Because dam and reservoir costs make up a large part of the total cost of hydroelectric installations, combination (3) (B) is rather common. Combination (3) (C), both prime and peaking capacity costing more than steam, is uneconomic for any installation. Such sites should not be developed until favorable price changes place them in a different classification. In all cases, the system load must be large enough and of such characteristics, that the capacity and energy available can be utilized.

Critical Incremental Plant Factor

Frequently, as the installation at a hydro plant is expanded, the net cost of peaking capacity changes from less than steam to more than steam, or from case (B) through case (A) to case (C). This occurs because of decreasing credits for secondary energy, and because additional hydro units may require more excavation, longer penstocks, etc., which increase the capacity cost. In such cases, there is an installation at which the net cost of hydro capacity equals the cost of steam capacity. This point determines the maximum economic installation at the site for conditions studied. It can be readily determined by comparing the net cost of a series of capacity increments with the cost of steam capacity. Table 3 illustrates the method. The energy output of the plant, shown in column 2, corresponds to the duration curve of Figure 2. The following costs, which are illustrative, apply to the assumed plant:

Prime power	$37.34 per kilowatt-year
Gross incremental capacity cost	$25.00 per kilowatt-year
Cost of steam capacity	$16.84 per kilowatt-year
Cost of steam energy	3.18 mills per kilowatt-hour

It is evident that the economic installed capacity is slightly over 35,000 kilowatts, since the increment from 35,000 to 40,000 kilowatts has a net cost greater than the steam-capacity cost of $16.84. In this example, the incremental cost of hydro capacity was assumed to be constant. In some cases this is not true, and the net cost (column 6) must reflect both variables. The installation for any case may be determined by graphical methods, if desired. However, for the case assumed, where the gross cost of peaking capacity at

market is constant over a fairly wide range of installations, the maximum economic capacity can be determined directly from the duration curve by first computing the critical incremental plant factor from the following equation:

$$C_h = C_s + (L \times 8760 \times V_e)$$

$$\text{or } L = \frac{C_h - C_s}{8760 \times V_e}$$

where C_h = gross annual cost of a 1-kw increment of hydro capacity, and related energy delivered to market

C_s = annual cost of 1 kw of steam capacity (no energy) at market

L = critical incremental plant factor, at market, expressed as a decimal fraction

V_e = value of energy at market in dollars per kwh

The critical incremental plant factor, as used herein, is defined by the above equation, and is the incremental plant factor at which the incremental net cost of hydro-peaking capacity changes from less than, to more than, steam-plant fixed costs.

Using the costs previously specified, the critical incremental plant factor, as found from the above equation, is 29.3 percent. Using the duration curve, Figure 2, it is evident that the total installed capacity corresponding to an incremental plant factor of 29.3 percent, is 37,000 kilowatts. This, therefore, is the maximum economic capacity of the proposed plant.

It is important to realize that if the net cost of hydro-peaking capacity is always less than the cost of steam capacity, there is no economic limit to the installation at the site. There is, however, at any stage of system development a very real practical limit, which will be determined by the amount of prime energy available and the minimum plant factor at which this energy is usable on the system load. As the system size increases and a greater proportion of steam power is added to the system, this practical plant factor becomes less, but rarely less than 10 percent, and it may be much higher. Each system must be studied individually, giving consideration to the load and the plants available to supply it. Using the notation previously developed, if a hydro-power project falls in combination (1) (B), (2) (B), or (3) (B), there is no economic limit to the installed capacity. However, if these combinations change to (1) (C), (2) (C), or (3) (C), respectively, there is a definite economic maximum; namely, the installation at which the incremental net cost of peaking capacity changes from less than, to more than steam. There is an exception to this statement in the case of combination (3) (B). If the costs are such that the addition of incremental capacity will not produce a benefit-cost ratio above unity at a practicable plant factor, there is no economic capacity, and the site should not be developed.

In most regions of the United States, the power load far exceeds that which could be served by available hydroelectric capacity; in others, it is growing at such a rapid rate that all economically feasible hydroelectric power probably will be fully utilized in the next three or four decades. It is apparent therefore, that in planning for the development of any hydro project, the possible future expansion of installed capacity that may become feasible should

be considered. If this is not done, later additions which should be made will be unduly costly or perhaps uneconomic. The amount that should be spent initially to provide for future installation depends, in large measure, on the interest rate and the probable date at which the capacity will be required. The maximum feasible future installation is a factor in this study, and is a part of any comprehensive basin planning. The methods outlined in the preceding discussion provide a quick and easy means of determining this factor with reasonable accuracy.

Recommended Procedures Applied to a System of Several Plants

Selection of installed capacity for a growing system passing through Phases I, II, and III, and having available four hydro plants with the cost used in the section on "Most Economic Hydro Plant Installation with Steam Support," is readily made with the data in Table 4. Unit cost data are the same as that previously used in Table 1.

It assumed that these are the only hydro plants available with costs less than steam.

Phase I

In Phase I, Plant B would be developed first as it has the lowest over-all cost. This plant alone could supply a load of 38,500 kilowatts (25000/.65 = 38,500). As load requirements increase (still in Phase I), Plants A, C, and D would be developed. Plant D would be developed only to its prime capacity, since there is no steam in the system, and hence little market for secondary energy. Peaking capacity would be distributed to Plants A, B, and C in more or less equal proportions, as their gross peaking costs are equal.

When the system-prime requirement reaches 100 average megawatts, corresponding to a peak of 153,846 megawatts at 65 percent load factor, all available prime hydro is being used; the average system cost is $27.68 per kilowatt (see Table 4); and secondary energy is wasted (as spilled water). The load requirements have been carved out of available hydro. Any further load growth will require steam for base load, and the system will pass from Phase I to Phase II.

Phase II

It has been shown that the steam required for the four separate systems is 89,522 kilowatts, when serving combined system peaks totaling 259,522 kilowatts. In the adverse year, steam is operating at a plant factor of 76.8 percent, although there are three hydro plants in the combined system where peaking can be installed at a gross cost less than that of steam-peaking capacity. Clearly, a lower system cost could be obtained by using this low-cost hydro-peaking capacity in place of steam, by putting steam entirely in the base of the load in the adverse year and reducing its size to 68,689 kilowatts —the minimum necessary to supply critical water-year energy (.65 x 259,522 - 100,000 = 68,689 kw). To properly locate the hydro plants on the load curve, Table 5 is prepared showing the gross and net incremental cost of hydro capacity for Plants A, B, C, and D.

The hydro-peaking capacity required is 90,833 kilowatts (259,522 - 100,000 - 68,689 = 90,833 kw). From Table 5, columns 7 and 9, the cheapest capacity increments are the first 5,000 kilowatts at Plants A, B, and C, so these increments are selected for installation. The next cheapest increment is at Plant D, where 5,000 kilowatts can be added at a small profit (excess in value of secondary energy over steam-capacity cost). Additional increments of 5,000 kilowatts each can now be added at Plants A, B, and C, followed by

5,000 kilowatts at Plant D. No further capacity will be added at Plant D for some time, since the next capacity increment costs $12.74 per kilowatt and cheaper capacity is available at Plants A, B, and C. Forty-thousand kilowatts out of the required 90,833 have now been chosen. The remaining capacity needed can be obtained by adding roughly equal increments to Plants A, B, and C, say, 20,000 at Plant A, 15,000 at Plant B, and 15,833 at Plant C. The installation would then be as follows:

Plant	Installed Kilowatts	
A	55,000	(The positions of these plants on the load are shown above the Phase II load curve on Figure 4.)
B	50,000	
C	50,833	
D	35,000	
Total Hydro	190,833	
Steam	68,689	
Total System	259,522	

The average unit cost of the system would be $26.54 per kilowatt of system peak, or $0.64 less than the cost obtained by combining the four "systems" of Table 1. (See Table 2, column 5)

The lower unit cost results in part from combining secondary energy with a small amount of steam energy to serve additional firm loads; and in part from the selection of lower-cost peaking-capacity additions, made possible by combining the four separate hydro-steam systems into a single system. One limitation of the isolated system method is its failure to take into account the increased flexibility possible when several plants are combined, and to take advantage of this by using the lowest-cost peaking capacity available.

The criterion of maximum return on the investment (maximum benefit-cost ratio) has also been used by some to determine hydro-plant installations. For purposes of comparison, such data are presented in Tables 4 and 6. Columns 5 and 6 of Table 4 were determined from calculations for each plant similar to those summarized for Plant A in Table 6. Obviously, the maximum return per dollar of investment in the hydro plant (maximum benefit-cost ratio) is of little assistance at any stage of development in arriving at the proper size of plant installation.

Phase III

The system, at the end of Phase II, has a peak load of 259,522 kilowatts. A load of at least 400,000 kilowatts seems certain to occur in the next few years, and the load shape is expected to remain the same. The possible supply for this load of 400,000 kilowatts will now be investigated.

Since the load shape is assumed to be the same, the energy requirement is 260,000 average kilowatts. In the adverse hydro year, 100,000 average kilowatts can be obtained from hydro and the remainder, 160,000, must come from steam. The minimum steam installation is, therefore, 160,000 kilowatts. From Table 5, columns (7) and (9), it is evident that additional hydro-peaking capacity is available at costs less than steam. The amount required is the difference between the system-peak demand, and the combined sum of steam capacity required and the existing hydro installation, or 400,000 - 160,000 -

190,833 = 49,167 kilowatts. Ten thousand kilowatts at Plant B and 9,167 at Plant C are the cheapest available increments, so these are chosen. The next cheapest increment is 5,000 kilowatts at Plant A, where there are 55,000 existing. A total of 24,167 kilowatts have now been selected, leaving 25,000 still required. The increment from 60,000 to 75,000 kilowatts at Plants A, B, or C is cheaper than the next increment (35,000 to 40,000) at Plant D, so the additional capacity should be placed among Plants A, B, or C. Since the costs are equal, the selection would be dependent on hydraulic, operating, or judgment factors. In this example, 5,000 kilowatts is installed at each A and B, and 15,000 at Plant C.

The economic installations required to carry the load of 400,000 kilowatts are, therefore, as follows:

Plant	Kilowatts
A	65,000
B	65,000
C	75,000
D	35,000
Total Hydro	240,000
Steam	160,000
Total	400,000

The loading corresponding to these installations is shown on the Phase III curve, Figure 4.

The system cost per kilowatt of system peak is $28.74 (see Table 7), or $2.20 per kilowatt per year more than the minimum cost obtained under Phase II. As the load grows and additional steam is installed, system cost will continue to increase.

The total hydro installation derived for the 400,000-kilowatt load is greater by 70,000 kilowatts than that determined by the isolated system method. This illustrates another disadvantage of the isolated system method, that is, the plant capacity so determined applies only to the system when it reaches the end of Phase II. Stated another way, the method fails to recognize opportunities to add hydro-peaking capacity costing less than steam as system load grows, and to identify projects which should be designed for future expansion.

The incremental method can be applied to any system. It requires prime energy, and net incremental cost data for all plants included in the study. It is the method recommended by the writers.

In applying the incremental method, special consideration must be given to cyclical-storage plants. The prime output and the cost of prime power at reservoir plants having cyclical storage, will likely be different for each phase of system operation. Careful consideration must be given to the changes in costs of prime power and peaking capacity that occur at such projects during their expected lives.

Special Problems of Installations at Storage Plants

Although the previous discussion applies equally to stream-flow and storage plants, there are many factors peculiar to the latter, which must also be considered in determining the most economic installation at each phase of

system development. At any given site various reservoir sizes are possible, and various methods of operation can be adopted. In most cases the problem is further complicated by multiple-purpose use of storage, by cost allocations, and by existing or proposed downstream power plants. In the discussion that follows, it is assumed that the size of the reservoir has been determined, and that storage drafts for purposes other than power are not controlling. If other reservoir sizes are to be investigated, the methods outlined should be applied to each size studied. If drafts for purposes other than power are controlling and cause loss of power value, then the values gained from the other purposes should exceed the power values lost. It is further assumed that cost-allocation problems have been solved, and do not enter into the question of reservoir operation or determination of installed capacity.

As storage is withdrawn from a reservoir the head on the turbine, and consequently the turbine capacity, is reduced. At some head full-gate turbine output will equal rated generator capacity plus losses, and further reduction in head will cause a loss in plant capability. This is termed "critical head" in this paper. If the power plant is to remain operative, the maximum drawdown possible is usually about 50 percent of maximum head. For this case the critical head will occur when drawdown is about 25 percent of maximum head, although some variation is possible.

The problem of reservoir operation divides itself into two parts—the first dealing with operations under a rule curve in which the maximum drawdown lies between maximum head and critical head; and the second with operations under a rule curve in which the drawdown is below critical head. In the first part of this problem, the additional draft on storage does not affect the dependable-peaking capability; only the amount of energy generated is affected. In the second part, which deals with drawdown below the critical head, both peaking capability and energy output are affected.

Optimum Drawdown

The optimum drawdown, whether above or below critical head, will utilize sufficient storage to make it possible to generate the maximum economic amounts of firm in Phase I, and of firm and secondary energy in Phases II and III. This drawdown is not necessarily the same each year, nor under each phase of system operation. The drawdown must be sufficient to provide enough hydro energy in each month of the critical period to permit at least that part of the peak in excess of the capacity of the steam plants or other hydro to be carried by the hydro plant. This amount is a maximum under Phase I conditions, and reduces to a minimum in Phase III.

Storage is used to regulate flows so that the minimum available hydro energy will equal firm hydro-capacity requirements, and in Phases II and III to provide as much steam-replacement energy as is economically feasible. The amount of the storage needed for firm hydro-energy production will depend upon the seasonal characteristics of the load, as well as upon the length of the critical period and the variation between critical-period and average streamflows. Since any draft on storage reduces the head, there will be a resulting loss of energy generated by reservoir inflows until the full head is recovered. To the extent that stored water is needed to permit the hydro plant to operate at required capacity under the load curve, such draft is readily justified, since the value of such releases for power production is greater than that of energy alone.

If storage in non-critical periods is drawn upon to a greater extent than needed to provide firm hydro energy to fulfill minimum hydro-capacity

requirements under the load curve, it must then be valued as steam replacement, and such draft can be justified only if it can be shown that otherwise the total hydro-energy generation would have been less. This situation could exist only if the water would otherwise be spilled. Since the maximum energy from any given inflow corresponds to the maximum head, the least draft should be made, consistent with energy conservation. However, it is better to use the water through a partial head, than to lose it altogether. Additional draft made in anticipation of a high inflow is equivalent to utilizing this inflow in advance at a reduced head, rather than spilling it; and is economical so long as firm capacity is not impaired.

In order to determine the optimum maximum drawdown in the spring of an average or better-than-average year (as indicated by available streamflow forecasts), it is necessary to compare two possible methods of operation—first, drawdown for firm energy only; second, to prevent as much spill as possible and still not impair firm peaking capacity. By following the first method, the drawdown might be insufficient to prevent spill, but would utilize the inflows to the reservoir through as high a head as possible. The second method would provide reservoir space in anticipation of any high flows that can be forecast, and would eliminate or reduce spill to a minimum. The two methods of operation are illustrated as follows:

	Storage Draft Period		Storage Refill Period		Storage Draft Period
Month	April	May	June	July	August
Method 1	Operate on stream flow at partial plant capacity	Operate on stream flow at partial plant capacity	Operate at full capacity reservoir filling	Reservoir full and spilling —Operate at full capacity	Reservoir full Aug. 1 Operate on streamflow and storage
Method 2	Operate at full capacity on stream flow and storage	Operate at full capacity on stream flow and storage	Operate at full capacity reservoir filling	Operate at full capacity reservoir filling	Reservoir full Aug. 1 Operate on streamflow and storage

The high inflow is used when it occurs to replenish the storage that has been withdrawn. In this way, energy is obtained from the high flows that otherwise would have been lost altogether. Such additional drafts on storage are unquestionably economical, as long as they do not reduce the capability of the hydro installation below monthly requirements, by drawing storage below the critical head at the time of system peak, or below that required in other months, in combination with other available capacity.

The economics of drawing storage below critical head will now be considered. This problem may be divided into two cases—drafts on storage, which do not reduce hydro capability below that required in the months following the excessive draft, and those which do. Obviously, if the firm-hydro capability is not reduced below that required in any month, there will be no loss of capacity value; therefore, in certain months when maximum hydro

capacity is not required, it is not important if the head be below critical, provided it is possible for the hydro plant to carry the load assigned to it.

If, however, the draft should result in a reduction in system firm-hydro capacity, owing to loss of head at times when needed, then the gain in energy saved must be such that its value exceeds the capacity value sacrificed. If steam-capacity value equated to hydro site is $18.00 per kilowatt, and steam-energy value equated to hydro site is 3 mills per kilowatt-hour, then the additional draft on storage would have to result in a net saving of: 18.00 ÷ .003 = 6000 kilowatt-hours per kilowatt of firm-hydro capacity sacrificed.

This saving, on the average, would have to be made annually. If the critical head and size of the hydro installation are properly chosen, it is unlikely that spilled energy of this magnitude could be salvaged by sacrificing head and firm capacity. Even if the equated cost of steam capacity were only $9.00 per kilowatt at hydro site, on the average 3000 kilowatt-hours or more per kilowatt lost would have to be salvaged to justify reducing the firm capability of the hydro plant. This is equivalent to slightly over four months' continuous operation.

However, this possibility should be fully explored. The actual effect upon capacity value of drawdown below the critical head should be computed and compared with the net gain in value of storable energy.

For plants located at reservoirs where the storage is large compared to the critical-period flow, an increase in flow during the critical period can be obtained by drawing below critical head. This may result in greater firm-energy output during the critical period, although it does not affect materially the average annual potential energy output. It is quite common practice, in Phase I system operations, to sacrifice peaking capacity at storage reservoirs, in order to increase system-prime energy.

The normal drawdown in each phase of operation should be selected so as to store all high flows in average or typical years that appear to come within the economic limits outlined, but not to impair the firm-energy requirements in the critical period. (The maximum drawdown in the West would probably occur in the late winter or early spring months, after the annual winter peak and before high releases are required for irrigation.) If the indicated economic gain due to increased drawdown is slight, it is better not to risk reducing firm-capacity output for an energy gain that cannot be definitely predicted. The smaller the power installation, the more likely it is that uncontrollable spill will occur in years of high runoff; therefore, it is probable that a sacrifice of capacity value that would be justified with a smaller installation, may be found uneconomic with a larger one. It is also true that the sacrifice of capacity value for a given gain in usable storage, by additional drawdown, is less for a small plant than a large one.

The general conclusion can, therefore, be reached that unless the energy is required for firm loads, it would not ordinarily be economical to draw below the minimum head at which required firm capability can be developed, unless downstream power plants are involved. Energy gains by such drawdown must be large and definite to justify this procedure.[9] In case the storage reservoir is above other hydro plants, the problem is somewhat different. The loss in firm capacity at the upper reservoir may be more than offset by gains at plants below the site.

9. If incremental hydro capacity, including transmission, is cheap compared with steam capacity, and incremental steam-energy costs are high, it may be economical to over-install the hydro plant in order to develop secondary energy. (See discussion under "Choice of Critical Head.")

For most cases in actual practice the effect of downstream plants can be evaluated by selecting a suitable increment of reservoir capacity just below critical head, assuming the increment of storage released and determining the capacity lost at the storage plant, and comparing its value with the value of the energy gained at the storage plant and at the downstream plants. This assumes that the downstream plants have sufficient energy available without the storage release, to make their capacity usable. If the reverse is true, then the storage release has a capacity value on the existing system load; and it is very likely justified until such time as system load growth would make the downstream capacity usable with its own energy. Justification beyond that period would depend upon the then existing circumstances.

The amount of capacity lost per acre-foot of drawdown at the storage plant, will depend on the shape of the area capacity curve and the installation at the plant. The energy gained at downstream plants will depend largely on the total head developed at these plants. Spill, or waste of stored water at downstream plants, may be a factor; and if it occurs must be taken into account. Table 8 gives the results of computations for a reservoir in the Pacific Northwest. It is assumed that the loss in capability occurs at time of system peak. Capacity value is taken as $16.50 per kilowatt-year at market, and energy at 3.72 mills per kilowatt-hour, also at market. Allowance is made for capacity losses of 10 percent and energy losses of 7 percent. Since all power facilities, including transmission, are installed to bring to market the rated capacity of the plant, and since these costs are incurred whether or not capacity is lost at the storage plant, the value of the capacity loss at site is not affected by transmission costs. The value is, therefore, $16.50 x .9 = $14.85 per kilowatt-year. The value of prime energy from storage cannot exceed, as a maximum, the cost of obtaining energy from a steam plant. For the case being studied, the average load factor for prime energy required from storage is 21.8 percent, which corresponds to a production of 1909.7 kilowatt-hours per year for each kilowatt of average-prime energy obtained from storage. For the installation considered, a drawdown that causes a capacity loss is not economic, even though the head developed below the plant is about 740 feet. If the head were increased to 1,500 feet, the first increment of drawdown would have a slight economic benefit.

Several routing studies made under the supervision of the writers indicate that little energy is gained at the storage site by drawdown below the critical head. More water is available, but it is used through a lower head and at a somewhat lesser efficiency; the net gain in energy is usually very small. Although this cannot be accepted as a general rule, as each reservoir presents a different case, it may be useful in preliminary studies.

As mentioned previously, as the system load grows and more of the load is supplied from fuel-electric sources, the amount of prime-hydro energy in the system becomes less important. In other words, the hydro capacity is dependably usable in the peak at lower load factors. In Phase I firm-system capacity is limited by hydro-prime energy, and the firm-energy value is at least equal to steam-electric energy cost. In Phase I, the value of secondary energy is relatively low, and will be based on sales of interruptible power. As steam-electric generation is added to the system, the value of potential hydroelectric-secondary energy begins to approach the value of steam energy.

After Phase III is reached, the value of prime energy and secondary are, for all practical purposes, the same—that is, equal to the cost of steam-energy generation. Cyclical hydro obtained by drawdown of reservoirs in the critical period becomes unprofitable if dependable-peaking values at site are

sacrificed. Such cyclic hydro energy can be replaced in Phase III at less cost to the system, by operating the steam plants at somewhat higher plant factors during critical periods. In most systems there will be very little secondary wasted, even during high flows, if the hydro-steam ratio is below 50-50. The hydro-steam ratio at which all seoondary is usable as steam-replacement energy depends upon the monthly load characteristics of the system, the amount and time of occurrence of secondary energy, and the minimum amount of steam generation required for reserves or other purposes.

Choice of Critical Head

Selection of the drawdown corresponding to the critical head, should be based on both the economics of the plant and the physical limitations of the turbine. For practical purposes, the critical head may be taken as about 75 percent of the maximum head, if the maximum drawdown is 50 percent.

A specified firm-hydro capacity can be maintained at somewhat lower heads than that corresponding to a 25 percent drawdown by increasing the size of the turbines, thus lowering the critical head, or by increasing the number of units without changing the turbine size. In the latter case, the capacity of transmission facilities also would be increased in order to permit delivery to market of whatever additional secondary energy could be produced.

The evaluation of gains and losses in these two cases is similar to that just described. In the first case (lowering the critical head and maintaining the generator output), penstock, tunnel, intake-control works, turbine, draft tube, tailrace, and similar costs would be increased, in order that the hydraulic capacity of the turbine may be great enough at the reduced head to operate the generator at full capacity. If these added costs should aggregate $50.00 per kilowatt of firm capacity, then the average-annual value of the additional energy obtained by reason of the drawdown below the critical head originally selected, should be worth as much as the annual fixed and operating charges on this investment, say $4.00 per kilowatt for a $50.00 investment. If energy is worth 2 mills per kilowatt-hour at site, 2000 kilowatt-hours must be generated, on the average, for each incremental kilowatt salvaged by means of the increase in hydraulic capacity.

In the second case (increasing the number of units in the plant in order to increase hydraulic capacity), the gain in secondary energy would have to be great enough to pay for the fixed and operating costs of additional generating facilities and transmission lines. If the total incremental investment cost of generating and transmission facilities is $150 per kilowatt, and the incremental fixed and operating costs are $15.00 per kilowatt, the increase in secondary-energy value per kilowatt needed to justify additional investment would be $15.00 per kilowatt, corresponding to 7500 kilowatt-hours per kilowatt at $.002. The incremental installed capacity would have some additional value in the system, but this is difficult to evaluate. Obviously, it would rarely be possible to salvage additional secondary energy in such quantities annually. But, undoubtedly, there are cases where lowering the critical head below 25 percent drawdown is economical for power purposes.

When a tentative rule curve and critical head have been selected, the project can be operated over a reasonably long representative water-supply period, and the proper installed capacity for any given system condition selected according to the principles previously outlined. As in many design problems, several investigations of the various factors may be necessary,

since there is considerable interdependence. Since the proper operation of a given reservoir will change with system load, the amount of steam support in the system, the developed downstream plants, the construction of other storage reservoirs on the system, changes in load characteristics, and probably other factors, proper reservoir operation is a matter for periodic review.

SUMMARY

Four criteria for determining the economic installation at hydro plants have been advocated:

1. Installation for maximum rate of return on investment.
2. Installation in which incremental capacity benefit-cost ratio is unity.
3. Installation for which over-all benefit-cost ratio is unity. (Now rarely used.)
4. Installation for lowest system cost.

Only Criterion 4 is applicable at all stages of system development, and is recommended in this paper.

Benefit-cost ratios of hydro projects determined by these criteria are rather commonly developed and used. Their significance and applicability vary considerably with the problem being considered.

The maximum hydro plant benefit-cost ratio (Criterion 1) is usually determined for several sizes of installation by comparing the corresponding total annual hydro costs with costs of equivalent steam-electric capacity and energy. The plant size having the highest benefit-cost ratio will produce the maximum return from the hydro plant per dollar of investment, if the power is sold at a price equal to the cost of equivalent steam-electric generation. The procedure by which this ratio is determined does not take into account the value of the hydro generation in combination with other hydro and steam plants to serve a system load. Its principal application is, therefore, limited to plants where the energy is produced for sale at wholesale, for maximum return.

The size of hydro installation may be further expanded until the cost of the last increment of capacity just equals the incremental benefit (Criterion 2). This measures the ultimate economic size of installation, but does not determine the size of installation at any particular time.

Criterion 1 may also be applied to a hydro plant with steam-plant support. The maximum benefit-cost ratio for a combined steam and hydro addition correctly indicates the best hydro-steam ratio and hydro plant size for a hydro plant site, based on steam capacity and energy as the sole alternative source of power. It indicates the size of hydro installation which, when combined with steam, will result in the lowest incremental cost per kilowatt of system peak obtainable from this single hydro-steam combination. Its application is limited. It does not take into account the possibility of obtaining peaking capacity and, usually, secondary energy at other plants; it does not recognize the flexibility that comes with system load growth and system additions to supply; and it fails to indicate the desirability of adding hydro-peaking capacity costing less than steam in Phase III. Nonetheless, it gives a reasonable hydro-plant installation, and very nearly the best benefit-cost ratio for a system comprised of several hydro and steam plants at the end of Phase II.

The incremental hydro benefit-cost ratio is a valuable tool for appraising

the value of firm and peaking capacity at various sites when system additions are based on Criterion 4. The net cost of each increment of hydro capacity is compared with the capacity cost of steam generation, both related to the same point on the system. Either this ratio, or the net peaking-capacity cost can be used to schedule system additions, since both place the potential capacity on a comparable basis.

The possibilities of obtaining peaking capability at a cost below steam should be determined, and the sites having the lowest incremental-capacity cost should be expanded, insofar as practicable, to furnish the required capacity. Other things being equal, steam plants should be used to furnish only the additional firm-energy requirements until all economic hydro-peaking capacity is used. This will give the best system economy at all times, and is the recommended method for planning plant installations.

There are seven significant combinations of prime-hydro costs and incremental-hydro costs—

(1)(A) hydro-prime capacity = steam;
hydro-incremental capacity = steam.

(Installation should be limited to prime output at system load factor until all peaking capacity costing less than steam is fully utilized.)

(1)(B) hydro-prime capacity = steam;
hydro-incremental capacity < steam.

(Installation limited by ability of load to make use of peaking capability.)

(1)(C) hydro-prime capacity = steam;
hydro incremental > steam.

(Installation should be limited to prime output.)

(2)(A) hydro-prime capacity < steam;
hydro incremental = steam.

(Minimum installation is equal to prime. No peaking capacity should be added until all peaking capacity costing less than steam is fully utilized.)

(2)(B) hydro-prime capacity < steam;
hydro incremental < steam.

(Same as (1)(B).)

(2)(C) hydro-prime capacity < steam;
hydro-incremental > steam.

(Installation, generally, should be limited to prime output.)

(3)(B) hydro-prime capacity > steam;
hydro incremental < steam.

(Installation above that required for an over-all benefit-cost ratio of 1:1 would be limited by ability of load to utilize additional peaking capability.)

The critical incremental plant factor at a hydroelectric plant is that plant factor at which the net cost of peaking capacity changes from less than steam-plant fixed costs to more than steam costs. If the peaking costs of all feasible installations at a hydro plant are less than steam-plant fixed costs, then there is no critical plant factor and the maximum installation must be determined on the basis of the minimum usable plant factor, or other criteria. The critical incremental plant factor can be determined in many instances, and in such cases it constitutes a useful and simple tool for determining maximum economically feasible installation.

If the gross cost of peaking capacity is constant over a fairly wide range of installations, the maximum economic capacity of the plant can be determined directly from the duration curve and the critical incremental plant factor.

There are three phases of system load growth:

Phase I — All peaking capacity and firm energy from hydro sources.
Phase II — Additional peaking capacity and firm energy from both hydro and steam sources.
Phase III — All additional firm energy and most additional peaking capacity from steam sources.

During Phase I of system development, all hydro projects that have costs of prime, or combined costs of usable capacity and energy, less than steam, should be built. Hydro-peaking capacity should, in general, be installed at the plants having the lowest net incremental costs. The installation should in no case exceed that calculated on the basis of the critical plant factor for incremental capacity, and usually will be less than that giving the highest hydro-plant benefit-cost ratio. The best size of installation under Phase II conditions should also be considered, and the installation limited to this size initially.

During Phase II, both steam plants and hydro plants are being added to the system. As system needs grow, all remaining hydro projects that are economically feasible should be built. Peaking capacity should always be supplied from the lowest-cost sources available. (See Figure 4 and Table 5.)

During Phase III, only those hydro-capacity additions having a net cost less than steam will be made. Additions to hydro capacity, where possible, should be made at projects having the lowest incremental net costs. Energy will be supplied almost entirely from steam sources.

At a storage plant it is necessary to determine optimum drawdown and critical head, that is, the head at which turbine and generator capacity are equal. Optimum drawdown will usually be such that no capacity losses occur at the storage plant, unless drawdown is required for firm energy, or unless there is considerable head developed below the storage plant. Drawdown below critical head occurring when the lost capacity is not needed is economic if it increases energy production.

Critical head may be varied by changing the turbine size in relation to the generator. The increased turbine size will have a certain cost, which must not exceed the value of the capacity made available at times of reduced head. Installation, optimum drawdown, and critical head at a storage plant are interrelated, and several studies may be needed before the best combination for a given reservoir is found. When critical head and optimum drawdown are determined, the reservoir should be operated with the rest of the system, and the proper installation determined from the methods outlined in the first part of this paper. The optimum drawdown will change as the system grows, and should be the subject of periodic review.

Table 1

SYSTEM COSTS OF COMBINED HYDRO AND STEAM-ELECTRIC GENERATION
For various hydro installed capacities, various hydro-steam ratios and corresponding system peaks.
(Based on 65% System Annual Load Factor)

Hydro Plant "A" Size (Kw) (1)	Cost ($/Kw) (1a)	Hydro Firm Energy (Avg. Kw/Kw inst.) (Kwh/Kw inst.) (2)	Hydro Average Energy (Avg. Kw/Kw Inst.) (Kwh/Kw inst.) (3)	Maximum Hydro-Steam Ratio Minimum Year (4)	Average Year (4a)
25,000	($37.34)	1.000 (8,760)	1.0 (8,760)	45-55(Hydro in Base)	45-55(Hydro in Base)
35,000	($30.36)	.714 (6,250)	.913 (8,000)	87.5-12.5(Hydro in Base)	60-40(Hydro in Base)
50,000	($25.16)	.500 (4,380)	.685 (6,000)	70-30(Hydro in Peak)	95-5(Hydro in Base)
60,000	($23.14)	.4167 (3,650)	.5859 (5,133)	60-40(Hydro in Peak)	84-16(Hydro in Peak)
75,000	($21.11)	.333 (2,920)	.484 (4,240)	52.5-47.5(Hydro in Peak)	66-34(Hydro in Peak)
100,000	($19.09)	.250 (2,190)	.377 (3,300)	44-56(Hydro in Peak)	57-43(Hydro in Peak)
125,000	($17.88)	.200 (1,750)	.31 (2,715)	35-65(Hydro in Peak)	50-50(Hydro in Peak)

Table 1 (Continued)

SYSTEM COSTS OF COMBINED HYDRO AND STEAM-ELECTRIC GENERATION
For various hydro installed capacities, various hydro-steam ratios and corresponding system peaks.
(Based on 65% System Annual Load Factor)

Assumed Hydro-Steam Ratio	System Peak	Available Hydro Energy: Min. Yr. (Kwh/Kw System Peak)	Available Hydro Energy: Avg. Yr. (Kwh/Kw System Peak)	Average Requirements Steam Energy (Kwh/Kw Syst.Pk.)	Cost of Steam Energy @ 3.18 mills/kwh ($/System Kw)	Cost of Plant Capacity @ 16.84/Kw ($/System Kw)	Cost of Hydro ($/System Kw)	System Production Cost ($/Kw)
(5)	(5a)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Plant A 25,000 Kw								
10-90	250,000	876	876	4,824	15.34	15.16	3.73	34.23
20-80	125,000	1,752	1,752	3,948	12.55	13.47	7.46	33.48
30-70	83,400	2,628	2,628	3,072	9.77	11.79	11.19	32.75
40-60	62,600	3,504	3,504	2,196	6.98	10.10	14.92	32.00
45-55	55,600	3,942	3,942	1,758	5.59	9.26	16.79	31.64
Plant A 35,000 Kw								
10-90	350,000	625	800	4,900	15.58	15.16	3.04	33.78
20-80	175,000	1,250	1,600	4,100	13.04	13.47	6.07	32.58
30-70	116,700	1,875	2,400	3,300	10.49	11.79	9.11	31.39
40-60	87,500	2,500	3,200	2,500	7.95	10.10	12.14	30.19
60-40	58,300	3,750	4,800	900	2.86	6.74	18.22	27.82
Plant A 50,000 Kw								
10-90	500,000	438	600	5,100	16.22	15.16	2.52	33.90
20-80	250,000	876	1,200	4,500	14.31	13.47	5.03	32.81
30-70	166,700	1,314	1,800	3,900	12.40	11.79	7.55	31.74
40-60	125,000	1,752	2,400	3,300	10.49	10.10	10.06	30.65
60-40	83,400	2,628	3,600	2,100	6.68	6.74	15.10	28.52
70-30	71,400	3,066	4,200	1,500	4.77	5.05	17.61	27.43
Plant A 60,000 Kw								
10-90	600,000	365	513	5,187	16.49	15.16	2.31	33.96
20-80	300,000	730	1,026	4,674	14.86	13.47	4.63	32.96
30-70	200,000	1,095	1,539	4,161	13.23	11.79	6.94	31.96
40-60	150,000	1,460	2,052	3,648	11.60	10.10	9.26	30.96
60-40	100,000	1,825	3,078	2,622	8.34	6.74	13.88	28.96
Plant A 75,000 Kw								
10-90	750,000	292	424	5,276	16.78	15.16	2.11	34.05
20-80	375,000	584	848	4,852	15.43	13.47	4.22	33.12
30-70	250,000	876	1,272	4,428	14.08	11.79	6.33	32.20
40-60	187,500	1,168	1,696	4,004	12.73	10.10	8.44	31.27
52.5-47.5	142,800	1,533	2,226	3,474	11.05	8.00	11.08	30.13
Plant A 100,000 Kw								
10-90	1,000,000	219	330	5,370	17.08	15.16	1.91	34.15
20-80	500,000	438	660	5,040	16.03	13.47	3.82	33.32
30-70	333,300	657	990	4,710	14.98	11.79	5.73	32.50
44-56	227,000	964	1,452	4,248	13.51	9.43	8.40	31.34
Plant A 125,000 Kw								
10-90	1,250,000	175	272	5,428	17.26	15.16	1.79	34.21
20-80	625,000	350	544	5,156	16.40	13.47	3.58	33.45
30-70	417,000	525	816	4,884	15.53	11.79	5.36	32.68
35-65	356,000	613	952	4,748	15.10	10.95	6.26	32.31

Table 1(Continued)

SYSTEM COSTS OF COMBINED HYDRO AND STEAM-ELECTRIC GENERATION
For various hydro installed capacities, various hydro-steam ratios and corresponding system peaks.
(Based on 65% System Annual Load Factor)

Hydro Plant "B" Cost ($/Kw) (13)	System Production Cost ($/Kw) (14)	Hydro Plant "C" Cost ($/Kw) (15)	System Production Cost ($/Kw) (16)	Hydro Plant "D" Cost ($/Kw) (17)	System Production Cost ($/Kw) (18)
		25,000 Kw			
30.00		45.00		30.00	
	28.35		35.10		28.35
		35,000 Kw			
25.15		35.87		26.89	
	24.69		31.12		25.73
		50,000 Kw			
21.51		29.01		24.55	
	24.88		30.13		27.01
		60,000 Kw			
20.09		26.35		23.64	
	27.13		30.89		29.26
		75,000 Kw			
18.68		23.68		22.73	
	28.86		31.48		30.98
		100,000 Kw			
17.27		21.02		21.83	
	30.54		32.19		32.55
		125,000 Kw			
16.42		19.42		21.28	
	31.80		32.85		33.50

Table 2

PHASE II SYSTEM COSTS 1/

Based on Cost of Separate
Hydro Plants with Steam Support

Hydro Plant in "System"	Best Hydro Steam Ratio	Best Size of Hydro Plant (Mw)	System Peak (Kw)	Hydro and Steam Cost/Kw of System Peak ($/Kw)	Total Cost Phase II ($1000)
(1)	(2)	(3)	(4)	(5)	(6)
A	70-30	50.0	71,428	27.43	1,959.27
B	60-40	35.0	58,333	24.69	1,440.24
C	70-30	50.0	71,428	30.13	2,152.13
D	60-40	35.0	58,333	25.73	1,500.91
		170.0	259,522	27.18	7,052.55

1/ Phase II costs are derived in Table 1.

Table 3

NET COST OF INCREMENTAL HYDRO CAPACITY
(Gross Cost = $25.00/Kw-Yr.)

Installed Capacity Kw (1)	Average Available Energy Million Kwh (2)	Increment of Capacity Kw (3)	Increment of Energy Avg. Kw/kw (4)	Value of Incremental Energy $ (5)	Net Cost of Incremental Capacity $/kw (6)
25,000	219				
		5,000	.822 1/	22.90 2/	2.10 3/
30,000	255				
		5,000	.571	15.91	9.09
35,000	280				
		5,000	.228	6.35	18.65
40,000	290				
		10,000	.114	3.18	21.82
50,000	300				
		10,000	.091	2.53	22.47
60,000	308				
		15,000	.076	2.12	22.88
75,000	318				
		25,000	.055	1.53	23.47
100,000	330				
		25,000	.046	1.28	23.72
125,000	340				

1/ $\frac{(255 - 219) \times 10^6}{5000 \times 8760} = .822$

2/ .822 x .00318 x 8760 = $22.90

3/ 25.00 - 22.90 = $2.10

Table 4

PHASE I SYSTEM COSTS

Hydro Plant	Hydro 1/ Plant Prime Avg. Mw	Cost of Prime ($1000)	Gross Cost of Hydro incr. Cap. ($/kw)	Best B/C 2/ (Based on Net Cost)	Hydro 2/ inst. for best B/C (Mw)	Usable 3/ Hydro inst. Phase I (Kw)	Cost of Incremental Hydro ($1000)	Total Cost Phase I ($1000)	Average Cost/kw of System Peak ($/kw)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
A	25.0	932.5	13.02	1.44	75.0	43,846	245.38	1,177.88	26.86
B	25.0	750.0	13.02	1.69	40.0	35,000	130.20	880.20	25.15
C	25.0	1,125.0	13.02	1.31	(Inf.)	50,000	325.50	1,450.50	29.01
D	25.0	750.0	19.10	1.57	35.0	25,000	0	750.00	30.00
Total	100.0	3,557.50	-	-	-	153,846	701.08	4,258.58	27.68

1/ All hydro plants assumed to have same potential power duration curve.

2/ Based on: $\frac{\text{(Cost of equivalent steam capacity and energy)}}{\text{(Hydro prime + incremental capacity cost)}}$

(All secondary energy assumed to be usable as steam replacement @ 3.16 mills per kwh.)

3/ Based on using all prime that can be peaked at system load factor at a cost less than steam; and on using lowest cost incremental capacity for peaking.

Table 5

NET COST OF INCREMENTAL CAPACITY
PLANTS A, B, C, AND D

Plants A, B, C, and D					Plants A, B, and C		Plant D	
Installation	Incremental	Secondary Energy in Increment		Value of Secondary	Gross Cost of Increment	Net Cost of Increment	Gross Cost of Capacity	Net Cost of Increment
Mw	Mw	Millions of Kwh	Avg. Kw/kw	$/kw	$/kw	$/kw	$/kw	$/kw
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
25								
	5	36	.8219	22.90	13.02	(9.88)1/	19.10	(3.80)
30								
	5	25	.5708	15.90	13.02	(2.88)1/	19.10	3.20
35								
	5	10	.2283	6.36	13.02	6.66	19.10	12.74
40								
	10	10	.1142	3.18	13.02	9.84	19.10	15.92
50								
	10	8	.0913	2.54	13.02	10.48	19.10	16.56
60								
	15	10	.0761	2.12	13.02	10.90	19.10	16.98
75								
	25	12	.0548	1.53	13.02	11.49	19.10	17.57
100								
	25	10	.0457	1.27	13.02	11.75	19.10	17.83
125								

1/ Value of secondary exceeds cost of capacity.

Table 6

EFFECT OF VARIOUS INSTALLATIONS ON HYDRO PLANT "A"
BENEFIT-COST RATIOS

Hydro Plant Size	Benefit-Cost Ratio For Increment	Benefit-Cost Ratio For Total Plant	LF Firm Energy (%)
(1)	(2)	(3)	(4)
25,000	1.20	1.20	100.0
30,000	3.05	1.32	83.3
35,000	2.52	1.39	71.5
40,000	1.79	1.42	62.5
50,000	1.54	1.43	50.0
60,000	1.49	1.44	41.7
75,000	1.45	1.44	33.3
100,000	1.41	1.43	25.0
125,000	1.39	1.43	20.0
175,000	1.29	1.40	14.3

The benefit-cost ratios for the various sizes of installations have been computed on the basis that all available secondary energy is salable for steam energy replacement and has been evaluated at 3.18 mills per kwh.

Table 7

PHASE III SYSTEM COSTS

Peak Load = 400,000 Kw
Load Factor = .65

Hydro Cost

Name	Plant Prime Power				Incremental Capacity			Total Hydro Plant Cost
	Installation	Amount	Unit Cost	Total Cost	Amount	Unit Cost	Total Cost	
	Kw	Kw	$/kw	$	Kw	$/kw	$	$
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
A	65,000	25,000	37.34	933,500	40,000	13.02	520,800	1,454,300
B	65,000	25,000	30.00	750,000	40,000	13.02	520,800	1,270,800
C	75,000	25,000	45.00	1,125,000	50,000	13.02	651,000	1,776,000
D	35,000	25,000	30.00	750,000	10,000	19.10	191,000	941,000
Total		100,000		3,558,500	140,000		1,883,600	5,442,100

Steam Cost

Capacity 160,000 Kw @ $16.84/Kw — 2,694,400

Energy cost:

System energy = 8760 x 400,000 x .65 = 2277.60 million kwh

Less hydro energy:

Plant	A	311.33	
	B	311.33	
	C	318.00	
	D	280.00	1220.66

Required steam energy — 1056.94 million kwh

Cost of steam energy = $1056.94 \times 10^6 \times 3.18 \times 10^{-3}$ — 3,361,069

Total system cost — 11,497,569

Cost per installed kw = $28.74 per kw year

Table 8

ECONOMIC DRAW-DOWN
PROPOSED RESERVOIR

Item			Increment 1		Increment 2		Increment 3	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Reservoir Elevation	Feet	2,358		2,340		2,319		2,300
Reservoir Content	Ac.Ft.	3,420,000		2,850,000		2,290,000		1,840,000
Incremental Content	Ac.Ft.		570,000		560,000		450,000	
Increase in Flow (242-day critical period)	Cfs		1,187		1,167		937	
Prime kw in critical period	Avg.Kw		63,500		62,400		50,100	
Unit value of energy at site	Mills/Kwh		3.46[1]/		3.46[1]/		3.46[1]/	
Average load factor of prime energy from storage	Percent		21.8		21.8		21.8	
Average energy from storage	Million Kwh		121.3		119.2		95.7	
Total value of energy	$		419,700		412,400		331,100	
Head of plant	Feet	304		286		265		246
Head of downstream plants	Feet	740		740		740		740
Percent of critical head	Percent	100		94.1		87.2		80.9
Percent of turbine capability[2]/	Percent	100		90.2		79.0		68.7
Incremental loss in capability 3/	Kilowatt		56,300		64,400		59,200	
Unit value of loss	$/Kw		14.85		14.85		14.85	
Total value of loss	$		836,000		956,000		879,000	

1/ 3.72 x .93 = 3.46
2/ Based on typical head-output curve.
3/ Installation = 575,000 kw.

FIGURE I

RELATIONSHIPS BETWEEN BENEFITS AND COSTS FOR VARYING SCALES OF DEVELOPMENT

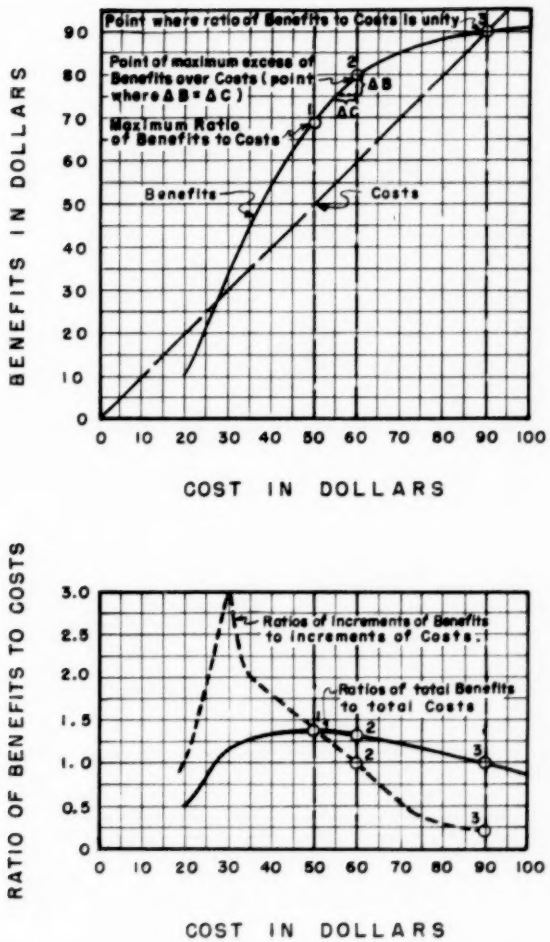

Point where ratio of Benefits to Costs is unity
Point of maximum excess of Benefits over Costs (point where ΔB = ΔC)
Maximum Ratio of Benefits to Costs
Benefits
Costs
ΔB
ΔC
BENEFITS IN DOLLARS
COST IN DOLLARS
RATIO OF BENEFITS TO COSTS
Ratios of increments of Benefits to increments of Costs
Ratios of total Benefits to total Costs
0 10 20 30 40 50 60 70 80 90 100
0 0.5 1.0 1.5 2.0 2.5 3.0

FIGURE 2

DURATION CURVE

PLANTS A, B, C & D

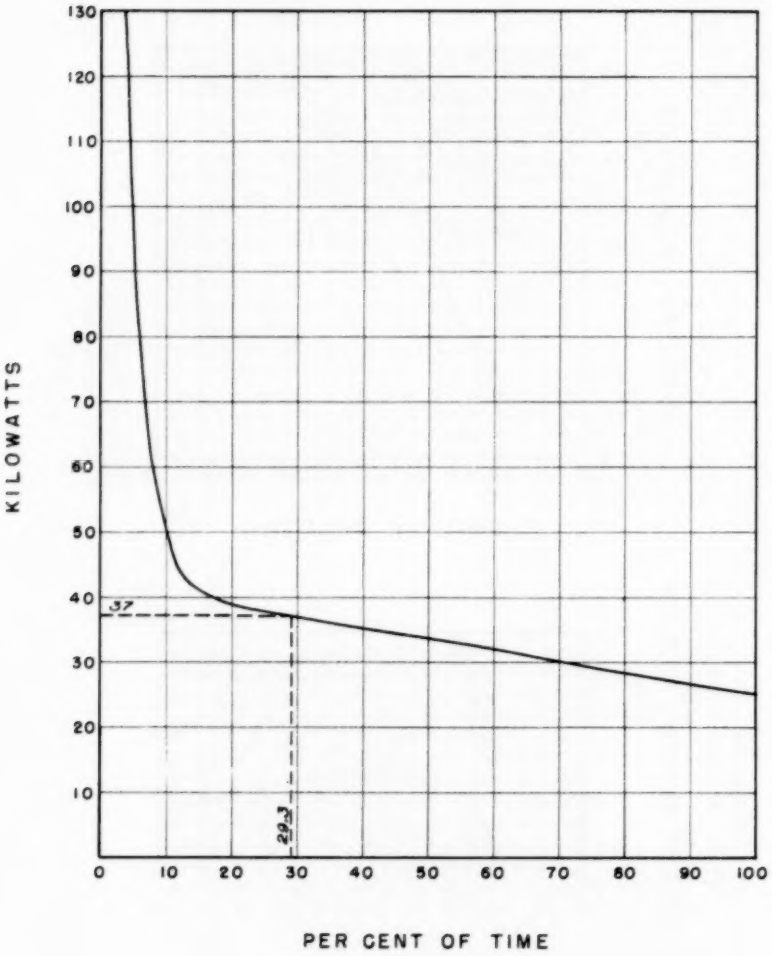
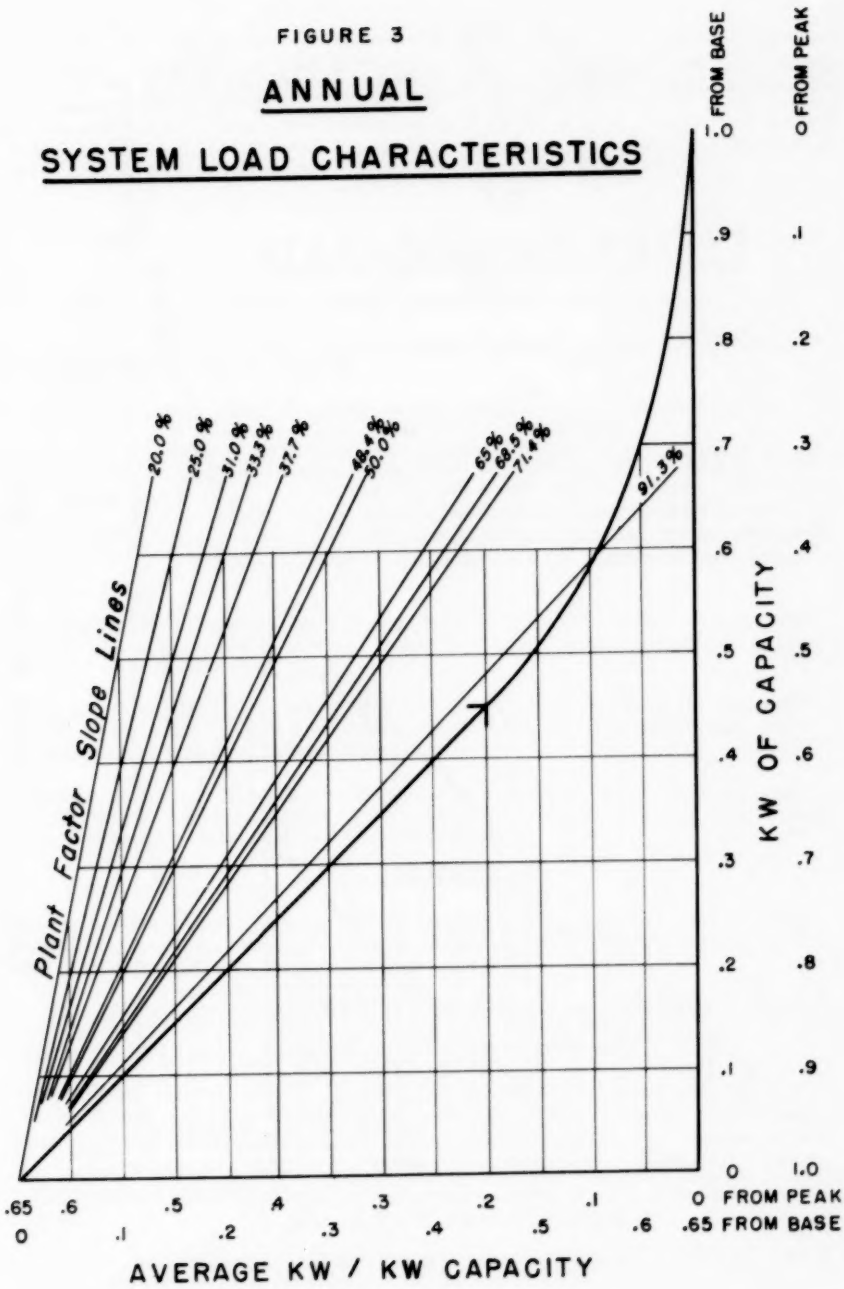


FIGURE 3

ANNUAL

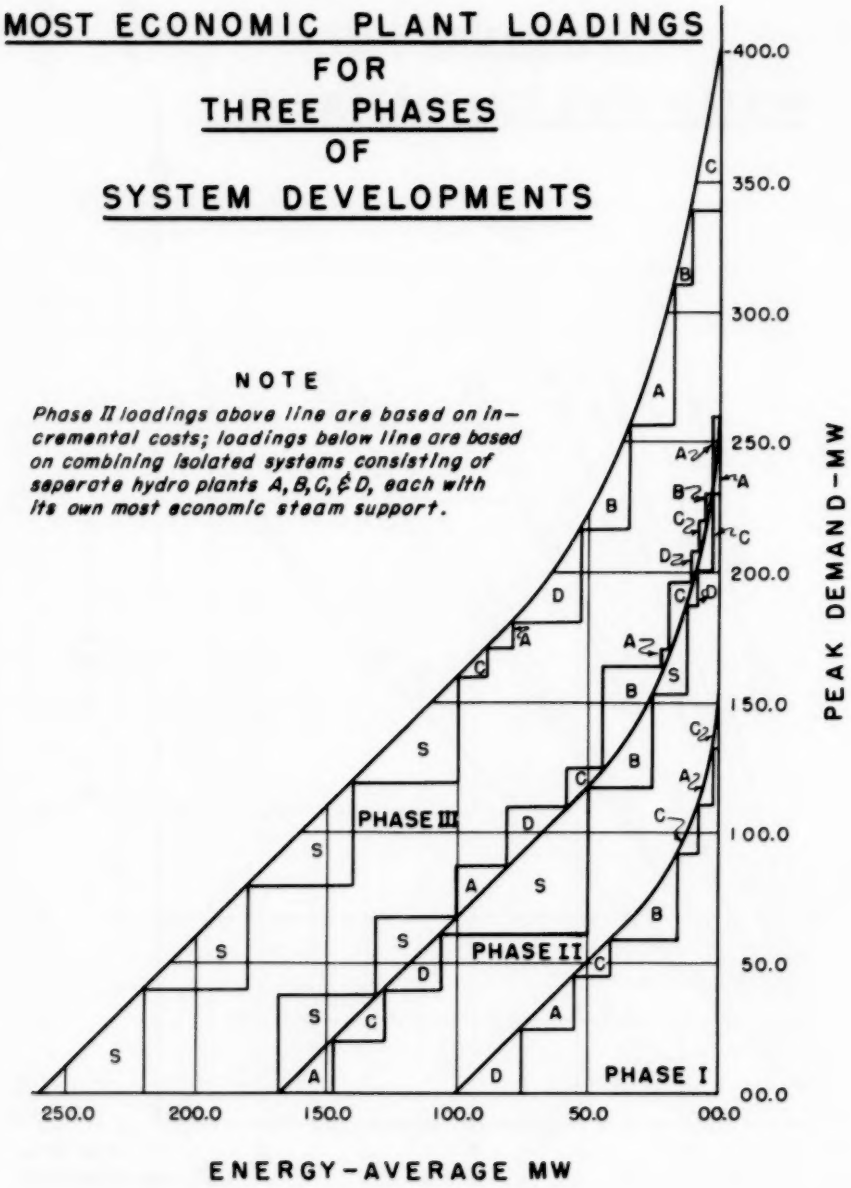
SYSTEM LOAD CHARACTERISTICS



697-35

FIGURE 4

MOST ECONOMIC PLANT LOADINGS FOR THREE PHASES OF SYSTEM DEVELOPMENTS



PROCEEDINGS-SEPARATES

The technical papers published in the past year are presented below. Technical-division sponsorship is indicated by an abbreviation at the end of each Separate Number, the symbols referring to: Air Transport (AT), City Planning (CP), Construction (CO), Engineering Mechanics (EM), Highway (HW), Hydraulics (HY), Irrigation and Drainage (IR), Power (PO), Sanitary Engineering (SA), Soil Mechanics and Foundations (SM), Structural (ST), Surveying and Mapping (SU), and Waterways (WW) divisions. For titles and order coupons, refer to the appropriate issue of "Civil Engineering" or write for a cumulative price list.

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MAY: 435(SM), 436(CP)[c], 437(HY)[c], 438(HY), 439(HY), 440(ST), 441(ST), 442(SA), 443(SA).

JUNE: 444(SM)[e], 445(SM)[e], 446(ST)[e], 447(ST)[e], 448(ST)[e], 449(ST)[e], 450(ST)[e], 451(ST)[e], 452(SA)[e], 453(SA)[e], 454(SA)[e], 455(SA)[e], 456(SM)[e].

JULY: 457(AT), 458(AT), 459(AT)[c], 460(IR), 461(IR), 462(IR), 463(IR)[c], 464(PO), 465(PO)[c].

AUGUST: 466(HY), 467(HY), 468(ST), 469(ST), 470(ST), 471(SA), 472(SA), 473(SA), 474(SA), 475(SM), 476(SM), 477(SM), 478(SM)[c], 479(HY)[c], 480(ST)[c], 481(SA)[c], 482(HY), 483(HY).

SEPTEMBER: 484(ST), 485(ST), 486(ST), 487(CP)[c], 488(ST)[c], 489(HY), 490(HY), 491(HY)[c], 492(SA), 493(SA), 494(SA), 495(SA), 496(SA), 497(SA), 498(SA), 499(HW), 500(HW), 501(HW)[c], 502(WW), 503(WW), 504(WW)[c], 505(CO), 506(CO)[c], 507(CP), 508(CP), 509(CP), 510(CP), 511(CP).

OCTOBER: 512(SM), 513(SM), 514(SM), 515(SM), 516(SM), 517(PO), 518(SM)[c], 519(IR), 520(IR), 521(IR), 522(IR)[c], 523(AT)[c], 524(SU), 525(SU)[c], 526(EM), 527(EM), 528(EM), 529(EM), 530(EM)[c], 531(EM), 532(EM)[c], 533(PO).

NOVEMBER: 534(HY), 535(HY), 536(HY), 537(HY), 538(HY)[c], 539(ST), 540(ST), 541(ST), 542(ST), 543(ST), 544(ST), 545(SA), 546(SA), 547(SA), 548(SM), 549(SM), 550(SM), 551(SM), 552(SA), 553(SM)[c], 554(SA), 555(SA), 556(SA), 557(SA).

DECEMBER: 558(ST), 559(ST), 560(ST), 561(ST), 562(ST), 563(ST)[c], 564(HY), 565(HY), 566(HY), 567(HY), 568(HY)[c], 569(SM), 570(SM), 571(SM), 572(SM)[c], 573(SM)[c], 574(SU), 575(SU), 576(SU), 577(SU), 578(HY), 579(ST), 580(SU), 581(SU), 582(Index).

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JANUARY: 583(ST), 584(ST), 585(ST), 586(ST), 587(ST), 588(ST), 589(ST)[c], 590(SA), 591(SA), 592(SA), 593(SA), 594(SA), 595(SA)[c], 596(HW), 597(HW), 598(HW)[c], 599(CP), 600(CP), 601(CP), 602(CP), 603(CP), 604(EM), 605(EM), 606(EM)[c], 607(EM).

FEBRUARY: 608(WW), 609(WW), 610(WW), 611(WW), 612(WW), 613(WW), 614(WW), 615(WW), 616(WW), 617(IR), 618(IR), 619(IR), 620(IR), 621(IR)[c], 622(IR), 623(IR), 624(HY)[c], 625(HY), 626(HY), 627(HY), 628(HY), 629(HY), 630(HY), 631(HY), 632(CO), 633(CO).

MARCH: 634(PO), 635(PO), 636(PO), 637(PO), 638(PO), 639(PO), 640(PO), 641(PO)[c], 642(SA), 643(SA), 644(SA), 645(SA), 646(SA), 647(SA)[c], 648(ST), 649(ST), 650(ST), 651(ST), 652(ST), 653(ST), 654(ST)[c], 655(SA), 656(SM)[c], 657(SM)[c], 658(SM)[c].

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MAY: 679(ST), 680(ST), 681(ST), 682(ST)[c], 683(ST), 684(ST), 685(SA), 686(SA), 687(SA), 688(SA), 689(SA)[c], 690(EM), 691(EM), 692(EM), 693(EM), 694(EM), 695(EM), 696(PO), 697(PO), 698(SA), 699(PO)[c], 700(PO), 701(ST)[c].

c. Discussion of several papers, grouped by Divisions.

e. Presented at the Atlantic City (N.J.) Convention in June, 1954.

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